Exhibit E

ExxonMobil

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ExxonMobil Pipeline Company Delivers Canadian Crude to Gulf Coast Refineries; Historic 20-Inch Pipeline Reversal Project A First in Industry

HOUSTON--(BUSINESS WIRE[1])--April 20, 2006--Mobil Pipe Line Company (MPLCO), an affiliate of ExxonMobil Pipeline Company, has started delivering Canadian crude to the U.S. Gulf Coast through an 858-mile crude oil pipeline that runs from Patoka, Illinois to Nederland, Texas. Deliveries to Beaumont, Texas-area refineries began in early April.

A first for the U.S. Gulf Coast region and Canadian crude producers, the successful completion of the 20-inch Pipeline Reversal Project gives shippers of western Canadian crude oil direct pipeline access to U.S. Gulf Coast refining markets. It also allows MPLCO to optimize a previously under-utilized pipeline to best advantage.

Mike Tudor, president of ExxonMobil Pipeline Company, said, "The 20-inch Pipeline Reversal Project is a win-win for the people of the Gulf Coast and Canada, the crude producers, refiners and ExxonMobil Pipeline. It is also an excellent example of our efforts to maximize the value of our pipeline and terminal assets. Canadian shippers have committed an average volume of 50,000 barrels per day for the next five years, and, in light of the high shipper interest, we anticipate that the pipeline will operate on average near its estimated capacity of 66,000 barrels per day in heavy crude service."

"The project team, from our Business Development group's work with Canadian producers to the engineering and operations activities in the field, did an exemplary job in implementing a project with a unique and valuable niche in the marketplace. The team worked over 240,000 hours, many in challenging winter conditions, without a recordable safety incident and we commend them for their utmost commitment to safety," he added.

The project reversed a 20-inch, 858-mile MPLCO crude oil pipeline that had historically run south-to-north from Nederland, Texas, to Patoka, Illinois. The 648-mile segment from Patoka to Corsicana, Texas, had been idle for several years, while the 210-mile segment from Corsicana to Nederland had been moving predominantly foreign crude north to markets in North Texas and Oklahoma.

The project has also enhanced synergies with Mustang Pipe Line Partners, a joint venture in which MPLCO has a 70% ownership share. Mustang operates a crude pipeline that extends from the Chicago area to Patoka, which allows access to other pipeline systems further north.

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(Adds Enbridge executive's comments, Altex Energy's pipeline plans)

DOW JONES NEWSWIRES

In a move to expand the market for Canadian crude oil into the heart of the U.S. refining industry, Enbridge Inc. (ENB) and Exxon Mobil Corp. (XOM) said they will study whether to build a new pipeline from an Illinois transportation hub to the Gulf Coast.

The project would run from the Patoka, Ill., oil storage and pipeline hub to Beaumont, Texas, and then onward to Houston. It would allow growing crude supplies from Canada to reach the Gulf Coast, home to nearly half of all U.S. refining capacity, with many of those refineries well suited to run lower- quality Canadian crude.

The newly disclosed intentions by two of North America's largest energy companies underscore the growing ties between the U.S., the world's largest oil consumer, and Canada, a growing crude power and largest exporter to the U.S. Consumers in the U.S. are looking increasingly to their northern neighbor for reliable supplies in an environment of high energy prices and continued instability in the Persian Gulf and elsewhere.

Richard Bird, Enbridge's executive vice president of liquids pipelines, said the companies were in talks with potential shippers of Canadian crude to determine the pipeline's capacity.

Based on the projected growth in Canadian crude output to more than 3 million barrels a day by 2015, a pipeline for about 400,000 barrels a day would be needed "by the early part of the next decade to move crude to the Gulf Coast," Bird said.

The interest from U.S. Gulf refiners will determine the eventual destination of the pipeline and how many refineries it could serve.

Bird added that "we would certainly expect" interest from Exxon Mobil's Gulf Coast refineries, as well as Imperial Oil Ltd. (IMO) on the production side. Exxon Mobil has a 70% stake in Imperial.

Potentially, the pipeline could be on stream by the end of 2010. Enbridge and Exxon Mobil would have to move at "a fair clip" to achieve this, but a decision by the end of the year "isn't outside the realms of possibility," Bird said.

The move comes as output is rising from Alberta's oil sands, even as much of the northern tier of the U.S. refining market is nearly saturated with Canadian crude.

Pipeline operators have already been rejiggering their networks to allow more Canadian crude oil to flow south. In April 2006, Exxon reversed an idle pipeline to have Canadian oil move from Patoka, Ill., to Nederland, Texas. A month earlier, Calgary-based Enbridge reversed a pipeline acquired from BP PLC (BP) to transport Canadian crude to Cushing, Okla., from Chicago. BP is looking at reversing a separate pipeline between those two sites.

Canada's prominence as a nearby, secure supplier of crude oil has many U.S. refiners considering modifications to better handle its higher-sulfur crude. ConocoPhillips (COP), one of the largest U.S. refiners, and EnCana Corp. (ECA) have forged joint ventures aimed at boosting use of Canadian crude, and Marathon Oil Corp. (MRO) has made clear its interest in partnering with a Canadian producer.

Calgary-based Altex Energy is planning another pipeline project to deliver Canadian crude to the Gulf Coast. The route would be much more direct than the Enbridge-Exxon Mobil proposal, traversing almost a straight line from northern Alberta to Texas.

The initial capacity is 250,000 barrels a day, and Chief Executive Jack Crawford said this would likely increase.

But the project was announced in 2005 and two years down the line, Altex has yet to make a formal application to Canada's National Energy Board. Crawford said the company was still in talks about shipping and offtake agreements, and he couldn't say when these would be in place.

At the earliest, the pipeline would come into service during 2011, compared with the Enbridge-Exxon Mobil target of 2010's end.

And the timing difference could be crucial, according to Bird.

"I don't see that there would be [the need] for two pipelines in the scale that we're talking about here for the next decade," Bird said. "There's only room for one."

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(Beth Heinsohn and Brian Baskin contributed to this article.)

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Increased oilsands production and refinery demand drives spending of $17 billion for new pipeline capacity

Godfrey Budd

Western Canada's pipelines are reaching the limits of their capacity. As a result, an estimated $16 or $17 billion will be invested in new pipelines and pumping stations over the next four or five years to bring increased oilsands production to market.

Reasons for additional oil transportation requirements aren't hard to find. In a report published in June this year, Crude Oil Forecast, Markets and Pipeline Expansions, the Canadian Association of Petroleum Producers (CAPP) says that western Canada's total crude oil supply could increase from 2.5 MMbbl/d in 2007 to 3.4 MMbbl/d in 2011. "This represents an average year-over-year growth rate of almost 230,000 bbl/d during this period," says CAPP.

In charting growth out to 2020, CAPP presents two production and supply cases for crude oil from the WCSB. In the more bullish Pipeline Planning Case, western Canadian crude oil supply is projected to increase from 2.4 MMbbl/d in 2006 to almost 5.3 MMbbl/d in 2020. In the Moderate Growth Case, supply rises to 4.6 MMbbl/d over the same period.

The difference between the two scenarios stems from a slower pace of development in some of the 25 or so thermal in situ projects, which are either under construction or in the planning stage, that is assumed in the Moderate Growth Case. In either case, says the CAPP forecast, "the expected growth in western Canadian crude oil supply will require additional pipeline capacity to meet demand from existing and new markets."

CAPP surveyed refineries in traditional and some potential new markets to gauge the incremental crude oil requirements. It found that, "demand for western Canadian crude oil by Canadian refineries is expected to rise from 765,000 bbl/d in 2006 to almost 1.1 MMbbl/d in 2015, a 44 per cent increase. As expected, the majority of the growth will be heavy crude oil and light synthetic." Over the same period, U.S. refinery demand for western Canadian crude will increase by 100 per cent—from about 1.6 MMbbl/d to almost 3.1 MMbbl/d. "Demand for heavy crude oil is by far the largest of the crude [oil] types," says CAPP.

At present, three major trunk pipelines—the Enbridge system, Kinder Morgan's Trans Mountain Pipeline and the Kinder Morgan Express-Platte pipelines—transport about 1.8 MMbbl/d of crude oil—which is just over 70 per cent of total western crude oil supply. In addition, the Enbridge and Trans Mountain systems also ship refined petroleum products out of western Canada.

The throughputs on all three of these pipeline systems, says the CAPP report, have recently been hit by capacity limitations. "Though these restrictions have been short-lived, western Canadian oil pipelines are reaching the limits of their capacity," says CAPP.

Based on its Pipeline Planning Case, the CAPP forecast says western Canada's pipeline system will need an additional 1 MMbbl/d of capacity by 2011. In fact, close to 1.3 MMbbl/d of new pipeline capacity for exporting crude from the WCSB is scheduled for completion by 2010.

Enbridge currently operates a vast pipeline system between Canada and the United States—described in the CAPP report as the world's longest crude oil pipeline—and can deliver more than 2 MMbbl/d of crude and other petroleum-based commodities from the WCSB to the U.S. Midwest and Ontario. It also connects to several lines in the United States, including Spearhead and Mustang, and receives crude from U.S. pipelines for delivery to markets in the U.S. Midwest and Ontario.

Like CAPP, Enbridge recently issued a forecast that anticipated increased demand from both U.S. and Canadian refiners. It has embarked on a raft of projects geared to increase shipments of oilsands-based crude. In 2005, Enbridge completed its Terrace Phase III expansion on its Lakehead Pipeline system, adding 130,000 bbl/d in capacity. Part of a $450-million expansion project, Phase III included construction of 193 km of pipeline between Clearbrook, MN, and Superior, WI.

In late 2006, Enbridge completed the first phase of its Southern Access program, adding about 38,000 bbl/d at Superior, WI. The second phase is underway and should boost shipping capacity out of Hardisty, Alta, by about 145,000 bbl/d as a result of enhancements to about 18 pumping stations along the line from Hardisty to Gretna, Man., near the U.S. border. The U.S. side of the Southern Access project will include 454 miles of new pipeline, tie-in with production sources in Montana and North Dakota, and shipping additional crude to the company's Flanagan terminal near Pontiac, IL. From there it will connect to the company's Spearhead pipeline.

The staged expansion has an initial capacity of 400,000 bbl/d and should be completed by 2009.

In May this year, Enbridge filed its application with regulatory authorities for its Alberta Clipper pipeline. The $3-billion project involves the construction of a 1,607 km, 36-inch pipeline from Hardisty to Superior, WI, mostly within or adjacent to existing rights-of-way. Initial capacity would be 450,000 bbl/d and could be expanded to 800,000 bbl/d. It should be in service in mid-2010.

Western Canada is expected to require new imports of diluent in order to export increasing amounts of heavy crude from the oilsands. Enbridge's Southern Lights project will involve construction of a 313-mile line of 20-inch pipe that will ship crude between Cromer, Man., and Clearbrook, MN, to replace the capacity of an existing line that will be converted to diluent service. Parts of the existing network of lines between refineries in the U.S. Midwest and Alberta will be reversed for shipping diluent north.

In addition to these projects, the new Enbridge Waupisoo pipeline will ship crude from the Cheecham terminal southeast of Fort McMurray along a 380 km, 30-inch pipeline to the company's Edmonton terminal. Initial capacity of the line is pegged at 350,000 bbl/d and is expandable to 600,000 bbl/d, says Jennifer Varey, manager for communications and stakeholder relations at Enbridge. Construction began in June this year, with commissioning scheduled for mid-2008.

Also scheduled to increase shipments out of the Fort McMurray region is the current expansion of the Kinder Morgan Corridor line, which runs from Shell Albian Sands to the Scotford upgrader near Edmonton. The expansion will add 240,000 bbl/d of incremental capacity to the line.

In early June, Enbridge and ExxonMobil made a joint announcement that further underlined what analysts see as a growing emphasis on oil shipments from Alberta's oilsands to markets within continental North America. The companies said they had agreed to work together to assess a possible pipeline that would ship Alberta crude from Patoka, IL, to Beaumont, TX, and on to Houston.
The proposed pipeline to the Gulf Coast, which would likely have capacity in the 400,000 bbl/d range, would dovetail well with planned increased shipments from Alberta's oilsands to the Chicago area. It could also further sideline Enbridge's delayed Gateway project that would ship crude to Kitimat, B.C., from Alberta.

Originally scheduled for service in 2009, Gateway could be delayed beyond 2012-2014, the schedule currently pegged by Enbridge as the in-service date for the pipeline. On July 12, PetroChina, which had had an agreement in principle with Enbridge to buy half the pipeline's proposed daily shipment of 400,000 bbl, announced that it was withdrawing support for the $4-billion project. An official with the China National Petroleum Company (CNPC), PetroChina's parent company, blamed Ottawa for not doing more to encourage Chinese investment in Canada and purchases of Canadian oil.

A July 14 story in the Globe & Mail reported that RBC Dominion Securities analyst Robert Kwan had written a note to clients warning that, "with half of the 400,000 [bbl/d] pipeline's support falling away," Gateway was unlikely to meet the 2012-2014 deadline. The same story also quoted an Enbridge spokesman who said the pipeline would be on schedule. He pointed to California and other Asia markets for Gateway crude.

The pipeline to the northern B.C. port would bring oil to tankers destined for either the U.S. Pacific Northwest or the Far East. "Right now, producers are saying they want to move more product to Chicago, also the Gulf Coast. That is a primary focus of a number of oil transmission companies. Gateway was envisaged as a new corridor to ship to Asia and California. Asia is considered a secondary market, as every drop of oil can go to the U.S. and Canadian markets, and the netbacks are better," says David McInnis, the president of the Canadian Energy Pipeline Association (CEPA).

An added advantage of the proposed 1,100 km Enbridge/Exxon pipeline is that it could run alongside a small Illinois-Texas line that opened last year. This could speed the development process if the project goes ahead. But, as the CAPP report observes, "The lead time to receive regulatory approvals and construct a new crude oil pipeline is at least four years."

Despite the host of oilsands-related pipelines that are in the works, most are likely to traverse relatively accessible and easy terrain and, McInnis says, "Projects won't be stalled as a result of an inability to access labour."

The Gulf Coast has some 7.5 MMbbl/d refining capacity. In 2006, it was using 2.4 MMbbl/d of heavy crude, much of it from Mexico and Venezuela. But both these sources are likely to become more problematic in the next few years, says Jack Crawford, president and CEO of Altex Energy Ltd. "Mexico's production is declining and is not being re-invested and Venezuela is uncertain. We have seen a growing interest in Canadian production more or less in proportion to what is going on in Venezuela. There is a high correlation," he says.

The Mexican declines and uncertainty surrounding Venezuela were possible factors in the increased shipments that were just announced for the TransCanada Keystone pipeline. The project, which is currently in regulatory review, will run from Hardisty to terminals at Wood River and Patoka, IL, with a further link to Cushing, OK, and is scheduled to be in service in late 2009. The $2.1-billion pipeline was to have had a capacity of 435,000 bbl/d, but on July 3, the pipeline operator announced that it had secured 155,000 bbl/d of additional firm contracts from Hardisty to Cushing.

The company obtained the commitments through a binding open season that was held in order "to support an expansion to 590,000 bbl/d and extension of the pipeline to Cushing. TransCanada has now secured long term contracts for a total of 495,000 bbl/d, with an average duration of 18 years," according to TransCanada's July 3 press release. The pipeline will include both new construction and the conversion of existing pipe that has been shipping natural gas.

Keystone will have capacity of about 435,000 bbl/d when it begins service in late 2009. The expansion and extension will involve additional pumping stations and the construction of a 473 km pipeline from the Kansas-Nebraska border to Cushing, with an in-service date of late 2010.

The growing attraction of the Canadian heavy oil option for U.S. refiners could boost the prospects of a proposed pipeline project that relatively small Altex Energy is working on. Including Crawford, most of the Altex team were founders and/or key players that led the development of the Alliance pipeline in the late 1990s. And Crawford sounds confident that his team of Alliance veterans can score big again.

The Calgary-based firm, with headquarters just blocks away from pipeline giants Enbridge and TransCanada, is working with a group of shippers, says Crawford, "to tie down operating details and tolling methodology before signing contracts." Originally planned for an initial capacity of 250,000 bbl/d, the line would be a contract carrier that would ship heavy crude from Fort McMurray via Fort Saskatchewan and Hardisty to the Gulf Coast. Costs have risen for the project—as they have for just about everything in the oil patch—since the concept was first developed and initial capacity might now be in the range of 300,000 bbl/d or slightly more.

The Altex link would include a stand-alone bullet line from Hardisty to the Gulf, and provide incremental export shipping capacity for oilsands-based product that analysts anticipate will be needed in 2011 and beyond. CAPP's Pipeline Planning Case forecasts that a further MMbbl/d will be needed by 2016, with yet another 700,000 bbl/d for 2020.

Altex—along with some other pipeline operators—could face stiff competition in 2011 and after, suggests Greg Stringham, a VP at CAPP. "There are a dozen or more pipeline proposals for post-2011," he says.

Crawford, on the other hand, points to his company's plans to use a non-diluent technology that doesn't have diluent's costly price dynamic. "None of the alternatives offers the economics that our proposal does," he says.

Northern gas pipelines face continued uncertainty

Only two major natural gas projects—Mackenzie and Alaska—are waiting in the wings. Their combined costs, however, would likely dwarf the total of all the oilsands pipeline-related projects through to about 2016—and possibly beyond.

Imperial recently announced a new costing of Mackenzie and pegged it at $18 billion. "Under the current cost estimate and fiscal regime, Mackenzie is not economic," says Chris Theal, a managing director at Tristone Capital. He adds, "The project was marginal three years ago." Back then, Imperial's original 2003 cost estimate of $7.6 billion was used for most discussion about the project.

A Tristone analysis of Mackenzie's cost structure that Imperial Oil announced in March estimates total supply costs for the project at US$5.78/Mcf. The analysis includes several recommendations. One is that the gathering system be regulated under the National Energy Board Act, which currently it is not. "We believe regulating the gathering system would provide the Explorers Group (a group of third-party producers with an interest in the project) access and fee certainty," says the Tristone paper, which was co-authored by Theal.

The paper also recommends an accelerated capital cost allowance that, it says, would be more in tune with the productive life of the project, and an increased debt/equity (D/E) ratio.

Another suggestion that Tristone makes is that government could provide loan guarantees, "much like the U.S. has for the Alaska Highway pipeline." This would help producers increase the D/E ratio. While Tristone's paper rules out government subsidies as politically a non-starter, it suggests that the cost of common infrastructure could be funded via federal/territorial/municipal bonds and access tolls. The paper's authors write, "In our opinion, there are fiscal solutions to bring supply costs down nine to 13 per cent and generate acceptable returns. Failure to come to terms will likely result in gas remaining dormant in the Delta for at least another 10 to 15 years."

The Alaska project has moved to a competitive bidding system. This, says Theal, is a better arrangement than the one that was rejected by the state's voters. Under the initial arrangement, the three majors that own most of the Alaska gas provided the government with a cost estimate. He says the price tag for the Alaska project, originally about $20 billion, could now cost in the $30- to $35-billion range. Besides the high cost, the project, like Mackenzie, is expected to face possible labour constraints, a complex regulatory process, and negotiations with First Nations.

As for timelines, McInnis estimates 2014 as the earliest complete date for Mackenzie and 2017 the earliest for Alaska